BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Madison Gas and Electric Company for Authority to Change Electric and Natural Gas Rates	Docket No. 3270-UR-114

DIRECT TESTIMONY OF GEORGE R. EDGAR AND WAYNE DE FOREST ON BEHALF OF THE CITIZENS UTILITY BOARD

September 8, 2005

I. INTRODUCTION

Q. Please state your names, titles and business addresses.

A. My name is George R. Edgar. I am the Director of Policy at Wisconsin Energy Conservation Corporation, 211 S. Paterson Third Floor, Madison, Wisconsin 53703.

My name is Wayne De Forest. I am the Senior Engineer at Wisconsin Energy Conservation Corporation, 211 S. Paterson Third Floor, Madison, Wisconsin 53703.

Q. Please summarize your educational background and experience.

A. Mr. De Forest: I have 27 years of experience in the industry performing cost studies, rate design, demand side management design, engineering and research. I worked at the Public Service Commission of Wisconsin for 12 years. My resume is attached as Exhibit ___ (E/D-1).

Mr. Edgar: I have approximately 25 years of experience in the industry, including as a Commissioner on the Public Service Commission of Wisconsin, and over the last 14 years as an energy policy and energy efficiency policy, program design and implementation consultant to various utility, consumer, environmental and public entities including state regulatory commissions. I have recently testified in the WPL CPCN proceeding concerning the Sheboygan Falls Facility; the We-Energies environmental trust bond case and in the most recent WPL and WPSC rate cases on cost of service and rate design issues. My resume is attached as Exhibit ___ (E/D-1).

Q. On whose behalf are you testifying in this and what is your assignment?

A. We are testifying on behalf of the Citizens Utility Board (CUB). We were asked by CUB to review the Applicant's electric and natural gas cost of service studies (COSS), the proposed class revenue requirement allocations, and the proposed electric and natural gas rate designs in this proceeding. CUB requested that we identify new opportunities for improved rate designs and the coordination of improved rate designs with energy efficiency and load management efforts for small customers.

Q. Please summarize your findings.

A. While our testimony presents several recommendations that would improve the cost of service studies performed by the Applicant as a guide to class revenue requirements, our primary focus is on the potential for improved residential rate designs to both help customers better control their energy bills and to help mitigate the future cost exposure of Madison Gas and Electric Company (MGE).

Our primary recommendation is that MGE undertake the development of a menu of new rate design options for residential customers to improve upon the existing seasonal flat rates and voluntary "time of use" (TOU) rate. The development of these options would, in addition, provide useful information for redesigning the integration and/or coordination of improved rate designs with demand-side programs (i.e. energy efficiency and load management). CUB and MGE have worked together prior to this hearing to develop a menu of rate design options that both parties agree would be valuable to continue to jointly analyze and develop.

Because of the current rate levels and the expected future cost increases for MGE customers, we recommend that "pilot" efforts to develop these new rate design options should commence as soon as possible so that initial designs can begin to be tested in the summer of 2006.

II. COST OF SERVICE/CLASS REVENUE REQUIREMENTS

Q. Do you agree with the class revenue requirement allocations proposed by the Applicant?

A. No. Because we do not yet know what any proposed revenue requirement adjustments by the Staff might be, our comments are based on the Applicant's proposed revenue requirement. The bottom line is that all of the Applicant's cost of service studies, including the Applicant's preferred study, indicate that residential customers are proposed to incur an increase that is in excess of any increase for residential services shown by any of those cost studies. This inappropriate result is compounded by the fact that the only cost study to indicate an increase even close to that proposed is the Applicant's preferred ("standard") cost study. (Direct Testimony of MGE witness James at p. 3.)

Q. Do you agree with the cost allocation methods used in the Applicant's preferred cost of service study?

A. No. There are important costs that the Applicant's preferred cost study has not properly allocated on the basis of direct cost causation. It has also allocated costs that cannot be allocated on the basis of direct cost causation in a manner that has a widely disparate impact among customer classes without an adequate justification for such disparities.

Our primary disagreements with the Applicant's preferred cost of service study are with: (1) the allocation of all electric generation capacity costs solely on demand; (2) the failure to allocate energy costs on the basis of on- and off-peak energy costs; (3) the use of a "minimum distribution system" approach to allocate part of the distribution system on a per customer basis; and (4) the failure to moderate the per kWh impacts of essentially "unallocable" costs such as the per customer costs of a "minimum distribution system" approach (if utilized) and

Administrative & General (A&G) costs. (See Direct Testimony of MGE witness Ziegler at pp. 3-4.)

Q. Do the other cost studies also presented by the Applicant better address the allocation of the above costs than the Applicant's preferred study?

A. Yes, they do. MGE witness Ziegler, in addition to presenting the Applicant's preferred cost study, also calculated the various cost study approaches typically presented by the Commission Staff. Based on these calculations, we believe that, using the Applicant's proposed revenue requirement, an appropriate increase for the residential class is between 0.66% and 1% (below the Time-of-Day (TOD) result of 1.28% and near to the Location result of 0.66%). (Exhibit___ (RAZ-2) at p. 2.)

Q. Please explain the basis for your recommendation of an increase no greater than 1% for residential customers.

A. The TOD study corrects for the Applicant's preferred cost study's allocating all generation costs solely on demand by allocating such costs on the basis of demand and energy, while also allocating energy costs on the basis of each class' on-peak energy use. (Direct Testimony of MGE witness Ziegler at p. 7, ll. 23-27) The Location study does not use the "minimum distribution system" approach to allocate part of the overall distribution system cost (although it does appropriately allocate meters and service costs on a customer-weighted basis). (*Id.* at p. 8, ll. 2-9.) As a result, our recommended limit of a 1% increase for residential customers reflects a treatment of generation capacity and energy costs based on direct cost causation, while somewhat moderating the impact of a "minimum distribution system" method (which we will explain, has no basis in direct cost causation and, without moderation, has an unjustified, adverse impact on small customers).

Q. Please explain why the use of a "minimum distribution system" approach has no basis in direct cost causation or even a meaningful indirect relationship.

A. A hypothetical "minimum distribution system" has no counterpart in the real utility world. It is similar to charging customers an entry fee to cover the cost of building a grocery store in order to have the opportunity to shop there. Utility distribution systems have been and are built because customers want to purchase energy services, not access.

The components and costs of a "minimum distribution system" (such as the cost of clearing land, digging trenches, putting up poles, installing transformers, etc.) are an inescapable, indivisible burden of installing any capacity at all. These indivisible outlays are in effect the basis of the economies of scale that allow greater demand to be met at lower cost than if separate distribution systems had to be built for different size customers based on their demand (both within and between customer classes). Allocating these "minimum system" costs on a per customer basis has the effect of providing the bulk of the benefits of a common distribution system to those customers who receive minimal cost allocation based on the number of customers. There is no basis in direct cost causation to assign economies in such a manner for a **c**ommon system that was built to provide energy services to all customers.

Q. Does the "minimum distribution system" method calculate costs that primarily vary on the basis of total number of customers?

A. As Professor Bonbright has explained about "minimum distribution system" costs:

> Their inclusion among the customer cost category is defended on the ground that, since they vary directly with the area of a distribution system they therefore vary *indirectly* with the number of customers.
>
> What this last-made cost imputation overlooks of course is the *very weak correlation* between area (or the mileage) of a distribution system and the number of customers served by the system. Indeed, if the company's service area stays fixed an increase in the number of customers does not necessarily betoken any increase whatever in the costs of a minimum size system.

James C. Bonbright, Principles of Utility Rates, 1961 Edition at 348. *(Emphasis added.)*

If a "minimum distribution system" approach is used, the resultant costs should be treated as "strictly unallocable" costs and not labeled as customer costs. (*Id.* at 347, 349.)

Q. Why is the appropriate allocation of "minimum distribution system" costs so important?

A. It is important not only because of the magnitude of such costs themselves, but even more because it affects allocators that are used to directly allocate a substantial amount of other costs. Therefore, the inappropriate allocation of such costs will allocate other costs that have little relationship to cost causation in a highly unequal manner without any compelling justification for such a result. The allocation of A&G (which are unallocable costs in their own right) is an example of other such costs whose allocation has an inappropriate, highly above average per kWh impact on small customers.

Q. How should "minimum distribution system" costs be treated for cost of service study purposes?

A. The most appropriate, and our preferred approach, is simply not to calculate a hypothetical "minimum distribution system" (which is the approach taken by most regulatory commissions). The alternative is to treat such costs as the "unallocable" costs that they really are and moderate the impact of allocating such costs on a per customer basis. Given the, at best, limited and very weak indirect basis underlying a per customer allocation, the impacts of the use of such a system should be moderated. This would be achieved by moving near the Location study results (which itself may even overstate class costs due to its highly unequal per kWh allocation of other unallocable costs such as A&G costs).

Q. Does your discussion of the "minimum distribution system" in the electric cost of service study extend to the Applicant's natural gas cost of service study?

A. Yes. The calculation of a "minimum gas main system" has all of the infirmities noted above for the electric "minimum distribution system" approach. The cost of natural gas mains should be fully allocated on the basis of demand and commodity to properly reflect why the costs of a gas main have been incurred (to provide a common system to meet the peak and commodity needs of customers).

Q. **Why does the TOD study present the appropriate methods to allocate costs on the basis of direct cost causation?**

A. The Applicant has allocated all generation capacity costs on the basis of demand. The TOD study recognizes that generation capacity costs are incurred to both: (1) ensure generation reliability and (2) to provide lower system energy costs. If the sole purpose of building a new generation unit is to meet system peak demand, a utility would build a peaking unit (a natural gas combustion turbine). However, utilities seek to build a new generation unit that not only meets system peak needs, but also reduces overall system energy costs. That is why they build baseload and intermediate units. The per kW incremental difference between the capacity costs of a peaking unit and a baseload or intermediate unit represents “capitalized energy” costs that reflect that higher capital costs are incurred (or “traded off”) to achieve the benefit of lower overall system energy costs (which are shared by all customers).

Thus, the demand-only allocation of generation capacity costs used by the Applicant fails to reflect the direct cost causation of why these generation costs are incurred and inequitably assigns such costs among the various customer classes. The appropriate cost allocation is called the “equivalent peaker” method in the NARUC Electric Cost Allocation Manual (1992 at 52-55). The 60/40% split between demand and energy typically used by Staff in the TOD method is appropriate for MGE.

The TOD study is also appropriate because it allocates energy costs on the basis of on-peak usage. Because energy costs are higher during on-peak periods, it is appropriate to allocate such costs among the various customer classes to recognize that fact.

Q. Are there other problems with the allocations made in the Applicant's cost of service studies?

A. Yes. All of the cost of service studies presented by the Applicant overstate the cost responsibility of firm customers, but especially the "preferred" COSS. It is our understanding that the demand allocator used in the various cost of service studies presented by MGE witness Ziegler does not include all of MGE's interruptible load. While interruptible customers should not pay for costs that they help avoid (such as the need for peaking capacity), many costs other than peaking capacity are allocated based on the "demand" allocator. By not including all interruptible load in the demand allocator for these latter costs, an interruptible customer will not be allocated costs that their presence does not avoid. As a result, other customers will be allocated more costs than are appropriate.

This problem is present in all of the cost of service studies, but the most serious misallocation occurs in MGE's "preferred" COSS. The reason for this is that generation capacity costs in that COSS include all of the capacity costs of baseload and intermediate units as well as peaking unit costs. Interruptible customers enjoy the benefits of using baseload and intermediate units to achieve lower system energy costs. However, by excluding some interruptible load from the demand allocator, these specific interruptible loads are not allocated any capacity costs for baseload and intermediate plants. Other customers are assigned these costs. A similar inappropriate result would occur for any purchase power agreement (PPA) that was entered into to acquire lower cost energy but is allocated in whole or primarily on demand.

Q. Please summarize your recommendation for class revenue requirement allocations in this proceeding.

A. The appropriate allocation of the Applicant's proposed revenue requirement to the residential class should be less than the results of the TOD study (1.28%) and nearer to the Location method (0.66%) but no more than 1%, if the Commission considers the use of a "minimum distribution system" approach. If the Commission appropriately recognizes that a "minimum distribution system" approach is not justified, the residential class should receive approximately a 0.66% increase as shown in the Location study.

A somewhat lower increase than shown in the Location study would also be appropriate and justified to: (1) moderate the impact of the unequal per kWh allocation of essentially unallocable costs such as A&G and (2) recognize the failure to include all interruptible load in the demand allocator for costs that interruptible customers do not avoid.

III. RATE DESIGN

Q. Do you have any general comments about residential rate design issues in this proceeding?

A. Yes. We believe that an overriding objective of rate design (in addition to providing an opportunity to recover the authorized revenue requirement) should be to provide appropriate price signals to those customers who are creating costs while also providing effective opportunities to those customers to modify their usage patterns to avoid such costs.

For a utility, the key cost factors from customer usage are the time of usage (e.g. on-peak), the level at which service is provided (e.g. primary or secondary distribution), the quantity of usage, and the cost to connect the customer to the system. More effective rate designs would provide customers an improved opportunity to control their own bills while mitigating future utility costs. In addition, improved time-differentiated pricing strategies based on Time-of-Use (TOU) should increase customer interest in the use of energy efficiency and load management options to reduce end-use peak loads that are hard to shift to different time periods, while encouraging shifting those loads more amenable to shifting to lower cost time periods.

Q. Have you discussed the potential benefits from improved rate designs with MGE?

A. Based on prior discussions, we understood that MGE was interested in investigating innovative approaches that would help their customers better control their energy bills. Both CUB and MGE are concerned about rising prices for customers. As a result, CUB and MGE have recently met several times to discuss and develop a menu of innovative residential rate designs that merit further analysis and development. This menu of innovative rate designs seeks to provide customers better price signals as to the cost of their consumption. It also proposes to blend rate design with energy efficiency and load management actions to maximize the potential value to customers of responding to these price signals. A further important focus of these efforts would be to find innovative ways to mitigate the need for MGE to make additional capital investment (i.e. increase costs) to implement valuable, improved rate design options.

Q. Please explain the nature of the CUB and MGE agreement about developing innovative rate design options for MGE's customers.

A. The development of effective rate designs requires a consideration of a range of issues. These issues include the cost-effectiveness of new rate designs (e.g. the hardware and software costs of providing adequate communications for Time-of

Use or Critical Peak Pricing rate designs), as well as the acceptability of such rates by various residential customers. Experience and common sense have persuaded CUB and MGE that a joint effort to develop, analyze and implement innovative ideas and approaches is in the best interests of MGE's customers. Cooperative efforts to investigate the likely costs and benefits, as well as the effectiveness of new rate designs, will result in better information and real-world results in a more timely manner than protracted arguments in a hearing room. Therefore, CUB and MGE have developed a range of innovate rate designs that they propose to jointly develop as an outcome of this proceeding**.**

Q. What rate design and related options do you believe merit further consideration and development?

A. We believe that CUB and MGE should continue to work together to develop the following specific rate design options and related matters, and present them to the Commission to be approved and implemented as pilot programs, if appropriate:

1. *Seasonal Inverted Block* rates instead of the current flat rate within the current seasonal rates and/or voluntary TOU rate for MGE that would establish a higher summer on-peak charge for usage above some base level (e.g. 600 kWh month). This design option could take advantage of existing metering already installed in the field and available for both General Service (Rg-1) and Time-of-Use (Rg-2) customers.

2. *TOU rates* based on an on-peak menu consisting of different per kWh charges reflecting different options available to customers to control their usage and the commensurate utility benefits produced, and a shorter on-peak period.

3. *Prescriptive rates* that provide a rate benefit if a customer takes a prescribed action to improve the cost impact of their usage on utility costs. A useful specific measure would be the installation of a high efficiency two-stage CAC unit or new high-efficiency dehumidifier. Developing such a program design that could be delivered through existing HVAC providers and integrated with the Focus on Energy program would increase the value of such efforts. These prescribed actions could include:

    - Lower on-peak charges for the participating customers
    - Up-front incentives that monetize the present value of a portion of future utility demand savings
    - Agreeing to use a load control device that allows MGE to control the second stage of a CAC unit or dehumidifiers during critical peak hours.

4. *Related Efforts:* A related area for inquiry would be to allow a customer to pay up front for the higher costs of more sophisticated metering (which could lower the cost to the customer), including the potential for customers to buy qualified equipment (e.g. controlling thermostats) directly from HVAC contractors that would accept the utility signal. Options of this type would allow MGE to offer different programs without having to directly make the capital investment necessary to implement the program.

Q. Please provide a specific example of the type of rate designs that CUB believes deserve further analysis and development.

A. Important determinants in the effectiveness of Time-of-Use rates are (1) the level of the on-peak rate; (2) the length of the on-peak period, and (3) the customer perception that they will actually receive a valuable benefit for taking service on the voluntary TOU rate.

Because even residential customers are different in their usage patterns and needs, a menu of TOU rate options, rather than a single option, may be more effective in soliciting increased participation on TOU rates. Therefore, a different array of on-peak rate options aligned with the magnitude of potential benefits created by changes in a customer's usage pattern would allow customers to find the best option to meet their needs but still create the overall system benefits desired.

An example of such a multi-option voluntary TOU rate could include the following components.

1. Off-peak rate 15% below the regular flat rate (e.g. 9 cents per kWh)
2. On-peak rate menu consisting of:
    a. Economy rate - (e.g. 11 cents per kWh)
    b. Moderate CAC - (e.g. 14 cents per kWh)
    c. Regular - (e.g. 19 cents per kWh)

Off-peak: The off-peak rate would apply throughout the year.

On-peak: The on-peak rate would apply for the summer months from 12:00 noon to 5:30 p.m. A customer would be able to choose from a menu of options that best fits their needs and interests and which helps mitigate future utility costs.

- **Economy on-peak rate**

The economy on-peak rate will provide a lower level of reliable central air conditioning on-peak than for customers on the moderate option and is for customers who desire air conditioning but do not depend on it between 12:00 noon and 5:30 p.m. during the week. The customer may buy a communicating thermostat that provides a reasonable degree of comfort and allows MGE to routinely reduce the level of air conditioning at times beyond the peak day. Customers paying for lower cost controls than communicating thermostats would risk the lowest level of air conditioning as MGE would routinely limit air conditioning to save peak energy costs. During extreme weather in conjunction with a capacity shortage, these customers will be turned off first and left off as long as needed for reliability reasons.

- **Moderate on-peak rate**

The moderate on-peak rate provides a comfort choice to customers while reducing peak energy use 50% below the peak level of the typical customer on the regular on-peak rate. Customers with high-efficiency central air conditioners (CAC of SEER 14 and above) are a primary target for this rate. Customers who allow control of the high stage of a two-stage CAC unit could also be eligible. Customers with inefficient CAC units could use the rate also if they agree to allow their CAC unit to be controlled to use no more than an efficient CAC unit between 12:00 noon and 5:30 p.m. During extreme weather in conjunction with a capacity shortage, the CAC units of these customers will be turned off only after interruptible customers and economy rate residential customers and will be controlled as needed for reliability reasons.

- **Regular on-peak rate**

The customers on the regular on-peak rate would in normal years choose how much central air conditioning they want to use and pay the rate applicable at the time of consumption. While generally unlikely to happen and unlikely to last long enough to impact comfort, the CAC units of these customers may be turned off as a last resort to avoid the cost of generation reserves for very rare situations. Control of these CAC units would only occur after all other controllable load has been interrupted.

Q. Do you have a recommended timeline for this rate design development?

A. Yes. We recommend that the Commission require that MGE file any tariffs necessary to develop and pilot some or all of the agreed-on efforts above by March 2006, so that they can be implemented by the summer of 2006. We believe that to meet this deadline, options would need to be identified by January 2006 for Commission Staff review. These "pilot" efforts would test the basic program designs (all of which would be voluntary options in addition to the existing rates) but also include customer research to test the viability and customer response to both voluntary and mandatory programs in the future. The expansion of effective pilot efforts to more residential customers would proceed as soon as practicable.

Q. Isn't the proposed timeline aggressive?

A. Yes, but it is for good reason. MGE customers face the prospect of continuing cost increases, including from the need for additional capacity either from new plant or through additional purchase power agreements. The sooner that effective efforts to mitigate the growth in customer demand can be implemented, the sooner that MGE rates may be returned to a more stable and reasonable level by mitigating the need for such an aggressive supply acquisition program. We recognize that other efforts will also be needed.

In prior discussions with MGE, we believe that it understands and supports the use of multiple, cost-effective approaches to provide reliable and reasonably priced service to its customers. The expeditious development and implementation of innovative and improved rate designs (including the improved integration and coordination of those rate designs with other demand-side management efforts) would further the attainment of that objective.

Q. How would the recovery of these potential costs of this redesign effort work?

A. It is our understanding that MGE may not have a rate case next year. Therefore, unless a recovery mechanism is established in this case (or costs could be adequately estimated for this test year) there will be a clear disincentive for MGE to pursue these efforts. While CUB is acutely concerned about current rate levels, the expenditures for this type of effort are important investments to provide small customers more effective options to control their bills and reduce future utility costs (and related adverse environmental and societal impacts from having to use increased supply resources). Therefore, CUB would support a well-designed recovery mechanism to ensure that MGE is able to adequately develop the options agreed to (e.g. an escrow or deferral mechanism as appropriate).

Q. Does this complete your direct testimony?

A. Yes, it does.